2. Derivatives and Risk in Energy Markets

Introduction

The general types of risk faced by all businesses can be grouped into five broad categories: *market risk* (unexpected changes in interest rates, exchange rates, stock prices, or commodity prices); *credit/default risk; operational risk* (equipment failure, fraud); *liquidity risk* (inability to pay bills, inability to buy or sell commodities at quoted prices); and *political risk* (new regulations, expropriation). In addition, the financial future of a business enterprise can be dramatically altered by unpredictable events—such as depression, war, or technological breakthroughs—whose probability of occurrence cannot be reasonably quantified from historical data.[4]

Businesses operating in the petroleum, natural gas, and electricity industries are particularly susceptible to market risk—or more specifically, *price risk*—as a consequence of the extreme volatility of energy commodity prices. To a large extent, energy company managers and investors can make accurate estimates of the likely success of exploration ventures, the likelihood of refinery failures, or the performance of electricity generators. Diversification, long-term contracts, inventory maintenance, and insurance are effective tools for managing those risks. Such traditional approaches do not work well, however, for managing price risk.

With the onset of domestic market deregulation in the 1980s, stable, administered prices for petroleum products and natural gas gave way to widely fluctuating spot market prices. Similarly, in the late 1990s, deregulation of wholesale electricity markets revealed that electricity prices, when free to respond to supply and demand, can vary by factors of more than 100 over periods of days or even hours. Spot prices for natural gas and electricity can also vary widely by location. International crude oil prices have long been volatile.

When energy prices fall, so do the equity values of producing companies; as a result, ready cash becomes scarce, and it is more likely that contract obligations for energy sales or purchases may not be honored. When prices soar, governments tend to step in to protect consumers. Thus, commodity price risk plays a dominant role in the energy industries, and the use of derivatives has become a common means of helping energy firms, investors, and customers manage the risks that arise from the high volatility of energy prices.

Derivatives are particularly useful for managing price risk. Their use in the energy arena is not surprising, in that they have been used successfully to manage agriculture price risk for more than a century. Deregulation of domestic energy industries has shown price risk to be greater for energy than for other commodities; in a sense, energy derivatives are a natural outgrowth of market deregulation. Derivatives allow investors to transfer risk to others who could profit from taking the risk, and they have become an increasingly popular way for investors to isolate cash earnings from fluctuations in prices.

Energy price risk has economic consequences of general interest because it can decisively affect whether desirable investments in energy projects are actually made. Investments in large power plants run from $200 million to over $1 billion, and the plants take 2 to 7 years to construct. Following general discussions of risk management without and with the use of derivatives, descriptions of various kinds of derivative contracts, and a brief analysis of energy price volatility, this chapter presents an illustration of the potential impact of price volatility on the economics of investment in a natural-gas-fired combined-cycle electricity generator. Combined-cycle generators are of particular interest because the Energy Information Administration (EIA) and other forecasters expect them to be the dominant choice for investments in new generating capacity over the next decade.[5] The example shows that an economically efficient investment, one that is in society's interest to undertake, could generate large cash losses that must be managed.

Risk Management Without Derivatives

When investors, managers, and/or a firm's owners are averse to risk, there is an incentive to take actions to

[4]F.H. Knight, *Risk, Uncertainty and Profit* (New York, NY: Century Press, 1964; originally published in 1921).

[5]Combined-cycle generating facilities are less capital-intensive than other technologies, such as coal, nuclear, or renewable electricity plants, but have higher fuel costs. In a recent EIA study, the share of natural-gas-fired generation in the Nation's electricity supply is projected to grow from 16 percent in 2000 to 32 percent in 2020. As a result, by 2004, natural gas is expected to overtake nuclear power as the Nation's second-largest source of electricity. See Energy Information Administration, *Annual Energy Outlook 2002,* DOE/EIA-0383(2002) (Washington, DC, December 2001).

reduce it. Diversification—investing in a variety of unrelated businesses, often in different locations—can be an effective way of reducing a firm's dependence on the performance of a particular industry or project. In theory it is possible to "diversify away" all the risks of a particular project;[6] in practice, however, diversification is expensive and often fails because of the complexity of managing diverse businesses.[7] More fundamentally, the success of most projects is strongly tied to the state of the general economy, so that the fortunes of various businesses and projects are not independent but move together. In the real world, therefore, diversification is often not a viable response to risk.

Another method of managing the risk created by fluctuating prices is to use long-term fixed-price contracts: the owner of a firm that invests in a natural gas combined-cycle plant could simply sign a long-term contract with a gas supplier. For example, in January 2002 it would have been possible to lock in gas prices of $2.59 per thousand British thermal units (Btu), $2.92 for 2003, and so on. However, such a hedging strategy still would leave some risk. If the spot market price for natural gas in 2003 turned out to be only $2.70 as opposed to $2.92, power from the firm's plant might not be competitive, because other plant owners could purchase natural gas at $2.70 and undercut the price of power from the plant with a higher fuel cost of $2.92. Conversely, if natural gas prices in 2003 rose to $4.00, the seller might choose to default on the plant's gas supply contract.

Insurance contracts can also be used to manage risk. For example, there is some probability that the natural gas plant in the previous example might malfunction and be taken out of service. The owner of the plant could purchase an insurance contract that would provide compensation for lost revenue (and perhaps for repair costs) in the event of an unplanned outage. The insurance would essentially shift the risks from the owner of the plant to the "counterparty" of the contract (in this case, the insurance provider). The counterparty would accept the risk if it had greater ability to pool risks and / or were less averse to risk than was the owner of the plant.

The plant owner could also reduce the risk of adverse movements in future natural gas prices by purchasing the fuel in the current period and storing it as inventory. If prices fell, the firm could buy the fuel on the open market; if they increased, it could draw down the inventory. This could be an expensive way to manage risk, because storage costs could be considerable.

Managing Risk With Derivative Contracts

Derivatives are contracts, financial instruments, which derive their value from that of an underlying asset. Unlike a stock or securitized asset, a derivative contract does not represent an ownership right in the underlying asset. For example, a call option on IBM stock gives the option holder the right to buy a specified quantity of IBM stock at a given price (the "strike price"). The option does not represent an ownership interest in IBM (the underlying asset). The right to purchase the stock at a given price, however, is of value. If, for instance, the option is to buy a share of IBM stock at $40, that option will be worth at least $60 when the stock is selling for $100. The option holder can exercise the option, pay $40 to acquire the stock, and then immediately sell the stock at $100 for a $60 profit.

The asset that underlies a derivative can be a physical commodity (e.g., crude oil or wheat), foreign or domestic currencies, treasury bonds, company stock, indices representing the value of groups of securities or commodities, a service, or even an intangible commodity such as a weather-related index (e.g., rainfall, heating degree days, or cooling degree days). What is critical is that the value of the underlying commodity or asset be unambiguous; otherwise, the value of the derivative becomes ill-defined.

The following sections describe various derivative instruments and how they can be used to isolate and transfer risk. Most of the discussion is in terms of price risk, but derivatives have also been developed with other non-price risks, such as weather or credit. When used prudently, derivatives are efficient and effective tools for reducing certain risks through hedging.

Forward Contracts

Forward contracts are a simple extension of cash or cash-and-carry transactions. Whereas in a standard cash transaction the transfer of ownership and possession of the commodity occur in the present, delivery under a forward contract is delayed to the future. For example, farmers often enter into forward contracts to guarantee the sale of crops they are planting. Forward contracts are sometimes used to secure loans for the farming operation. In energy markets, an oil refiner may enter into forward contracts to secure crude oil for future operations, thereby avoiding both volatility in spot oil prices and the need to store oil for extended periods.

[6]To get a riskless portfolio would require that the average correlation across all asset pairs be zero—a stronger condition than having a particular asset uncorrelated with the rest of the portfolio.

[7]P.G. Berger and E. Ofek, "Diversification's Effect on Firm Value," *Journal of Financial Economics*, Vol. 37 (1995), pp. 39-65.

Forward contracts are as varied as the parties using them, but they all tend to deal with the same aspects of a forward sale. All forward contracts specify the type, quality, and quantity of commodity to be delivered as well as when and where delivery will take place. In addition, forward contracts set a price or pricing formula. The simplest forward contract sets a fixed (firm) price. More elaborate price-setting mechanisms include floors, ceilings, and inflation escalators. By setting such a price, the buyer and seller are able to reduce or eliminate uncertainty with respect to the sale price of the commodity in the future. Knowing such prices with certainty may allow forward contract users to better plan their commercial activity. Finally, the contract may contain miscellaneous terms or conditions, such as establishing the responsibilities of the parties under circumstances where one party fails to perform in an acceptable manner (lack of delivery, late delivery, poor quality, etc.). Overall, forward contracts are designed to be flexible so as to match the commercial merchandising needs of the parties entering into them.

A direct result of the forward pricing and delivery features of forward contracts are default and credit risks. In the case of long-term forward contracts, the exposure to default and credit risks may be substantial. Parties to forward contracts must be concerned about the other party's performance, particularly when the value of the contract moves in one's favor. For example, if an oil refiner has contracted to purchase oil at $19 per barrel, its level of concern that the other party will perform by delivering oil rises progressively as the price of oil rises above $19 per barrel and the incentive for the counterparty to "walk away" from the contract increases. To deal with the risk of default, parties scrutinize the creditworthiness of counterparties and deal only with parties that maintain good credit ratings. They may also limit how much they will buy from or sell to a particular trader based on his credit rating. In some circumstances parties may also ask counterparties to post collateral or good faith deposits to assure performance. Ultimately, how parties deal with default and credit risk in a forward contract is up to them.

Futures Contracts

Futures trading in the United States evolved from the trading of forward contracts in the mid-1800s at the Chicago Board of Trade (CBOT). By the 1850s, the practice of forward contracting had become established as farmers and grain merchants in the Midwest sought to reduce their exposure to changes in the price of grain they were producing or storing.[8] After the CBOT standardized forward contracts, speculators began to purchase and sell the contracts in an effort to profit from the change in the value of the contracts. Actual delivery of the commodity became of secondary importance.[9] Eventually this practice became institutionalized on the CBOT, and the modern futures contract was born. Today futures contracts are traded on a number of exchanges in the United States and abroad (Table 1).

Forward contracts have problems that can be serious at times. First, buyers and sellers (counterparties) have to find each other and settle on a price. Finding suitable counterparties can be difficult. Discovering the market price for a delivery at a specific place far into the future is also daunting. For example, after the collapse of the California power market in the summer of 2000, the California Independent System Operator (ISO) had to discover the price for electricity delivered in the future through lengthy, expensive negotiation, because there was no market price for future electricity deliveries. Second, when the agreed-upon price is far different from the market price, one of the parties may default ("non-perform"). As companies that signed contracts with California for future deliveries of electricity at more than $100 a megawatt found when current prices dropped into the range of $20 to $40 a megawatt, enforcing a "too favorable" contract is expensive and often futile. Third, one or the other party's circumstances might change. The only way for a party to back out of a forward contract is to renegotiate it and face penalties.

Futures contracts solve these problems but introduce some of their own. Like a forward contract, a futures contract obligates each party to buy or sell a specific amount of a commodity at a specified price. Unlike a forward contract, buyers and sellers of futures contracts deal with an exchange, not with each other. For example, a producer wanting to sell crude oil in December 2002 can sell a futures contract for 1,000 barrels of West Texas Intermediate (WTI) to the New York Mercantile Exchange (NYMEX), and a refinery can buy a December 2002 oil future from the exchange. The December futures price is the one that causes offers to sell to equal bids to buy—i.e., the demand for futures equals the supply. The December futures price is public, as is the volume of trade. If the buyer of a December futures finds later that he does not need the oil, he can get out of the contract by selling a December oil future at the prevailing price. Since he has both bought and sold a December oil future,

[8]For a detailed discussion of the early development of futures trading, see T.A. Hieronymus, *Economics of Futures Trading for Commercial and Personal Profit* (New York, NY: Commodity Research Bureau, Inc., 1971), pp. 73-76.

[9]A forward contract takes on a value when the price expected to exist at the time of delivery deviates from the price specified in the forward contract. For example, if a forward contract specifies a price of $19 per barrel for crude oil and the price expected to exist at the time of delivery rises to $20 per barrel, the value of the contract from the perspective of the party taking delivery is $1 per barrel, in that the party could take delivery of the oil and immediately sell it at a profit of $1 per barrel. Conversely, the value of the contract to the party making delivery is -$1 per barrel.

he has met his obligations to the exchange by netting them out.

Table 2 illustrates how futures contracts can be used both to fix a price in advance and to guarantee performance. Suppose in January a refiner can make a sure profit by acquiring 10,000 barrels of WTI crude oil in December at the current December futures price of $28 per barrel. One way he could guarantee the December price would be to "buy" 10 WTI December contracts. The refiner pays nothing for the futures contracts but has to make a good-faith deposit ("initial margin") with his broker. NYMEX currently requires an initial margin of $2,200 per contract. During the year the December futures price will change in response to new information about the demand and supply of crude oil.

In the example, the December price remains constant until May, when it falls to $26 per barrel. At that point the exchange pays those who sold December futures contracts and collects from those who bought them. The money comes from the margin accounts of the refiner and other buyers. The broker then issues a "margin call," requiring the refiner to restore his margin account by adding $20,000 to it.

This "marking to market" is done every day and may be done several times during a single day. Brokers close out parties unable to pay (make their margin calls) by selling their clients' futures contracts. Usually, the initial margin is enough to cover a defaulting party's losses. If not, the broker covers the loss. If the broker cannot, the exchange does. Following settlement after the first change in the December futures price, the process is started anew, but with the current price of the December future used as the basis for calculating gains and losses.

In September, the December futures price increases to $29 per barrel, the refiner's contract is marked to market, and he receives $30,000 from the exchange. In October, the price increases again to $35 per barrel, and the refiner receives an additional $60,000. By the end of November, the WTI spot price and the December futures price are necessarily the same, for the reasons given below. The refiner can either demand delivery and buy the oil at the spot price or "sell" his contract. In either event his initial margin is refunded, sometimes with interest. If he buys oil he pays $35 per barrel or $350,000, but his trading profit is $70,000 ($30,000 + $60,000 - $20,000. Effectively, he ends up paying $28 per barrel [($350,000 - $70,000) /

Table 1. Major U.S. and Foreign Futures Exchanges

Exchange	Country	Primary Commodities
Chicago Board of Trade (CBOT)	USA	Grains, US Treasury notes and bonds, other interest rates, stock indexes
Chicago Mercantile Exchange (CME)	USA	Livestock, dairy products, stock indexes, Eurodollars and other interest rates, currencies
Kansas City Board of Trade (KCBT)	USA	Wheat and stock indexes
Minneapolis Grain Exchange (MGE)	USA	Spring wheat
New York Board of Trade (NYBOT)	USA	Sugar, coffee, cocoa, cotton, currencies
New York Mercantile Exchange (NYMEX)	USA	Metals, crude oil, heating oil, natural gas, gasoline
Philadelphia Board of Trade (PBOT)	USA	Currencies
Bolsa de Mercadorias & Futuros (BMF)	Brazil	Gold, stock indexes, interest rates, exchange rates, anhydrous fuel alcohol, coffee, corn, cotton, cattle, soybeans, sugar
EUREX	Germany/Switzerland	Interest rates, bonds, stock indexes
Hong Kong Futures Exchange (HKFE)	Hong Kong	Stock indexes, interest rates, currencies
International Petroleum Exchange (IPE)	England	Crude oil, gas oil, natural gas, electricity
London International Financial Futures Exchange (LIFFE)	England	Interest rates, stock indexes, bonds, coffee, sugar, cocoa, grain
London Metals Exchange (LME)	England	Copper, aluminum, lead, zinc, nickel, tin, silver
Marche Terme International de France (MATIF)	France	Bonds, notes, interest rates, rapeseed, wheat, corn, sunflower seeds, stock indexes
MEEF Renta Fija	Spain	Bonds, interest rates, stock indexes
Singapore Futures Exchange	Singapore	Interest rates, stock indexes, crude oil
Sydney Futures Exchange	Australia	Interest rates, stocks, stock indexes, currencies, electricity, wool, grains
Tokyo Grain Exchange (TGE)	Japan	Corn, soybeans, red beans, coffee, sugar
Tokyo International Financial Futures Exchange (TIFFE)	Japan	Interest rates, currencies

Source: Commodity Futures Trading Commission.

Table 2. Example of an Oil Futures Contract

Date	Prices per Barrel: WTI Spot	Prices per Barrel: December Future	Contract Activity	Cash In (Out)
January	$26	$28	Refiner "buys" 10 contracts for 1,000 barrels each and pays the initial margin.	($22,000)
May	$20	$26	Mark to market: (26 - 28) x 10,000	($20,000)
September	$20	$29	Mark to market: (29 - 26) x 10,000	$30,000
October	$27	$35	Mark to market: (35 - 29) x 10,000	$60,000
November (end)	$35	$35	Refiner either: (a) buys oil, or	($350,000)
			(b) "sells" the contracts.	
			Initial margin is refunded.	$22,000

Source: Energy Information Administration.

10,000], which is precisely the January price for December futures. If he "sells" his contract he keeps the trading profit of $70,000.

Several features of futures are worth emphasizing. First, a party who elects to hold the contract until maturity is guaranteed the price he paid when he initially bought the contract. The buyer of the futures contract can always demand delivery; the seller can always insist on delivering. As a result, at maturity the December futures price for WTI and the spot market price will be the same. If the WTI price were lower, people would sell futures contracts and deliver oil for a guaranteed profit. If the WTI price were higher, people would buy futures and demand delivery, again for a guaranteed profit. Only when the December futures price and the December spot price are the same is the opportunity for a sure profit eliminated.

Second, a party can sell oil futures even though he has no access to oil. Likewise a party can buy oil even though he has no use for it. Speculators routinely buy and sell futures contracts in anticipation of price changes. Instead of delivering or accepting oil, they close out their positions before the contracts mature. Speculators perform the useful function of taking on the price risk that producers and refiners do not wish to bear.

Third, futures allow a party to make a commitment to buy or sell large amounts of oil (or other commodities) for a very small initial commitment, the initial margin. An investment of $22,000 is enough to commit a party to buy (sell) $280,000 of oil when the futures price is $28 per barrel. Consequently, traders can make large profits or suffer huge losses from small changes in the futures price. This *leverage* has been the source of spectacular failures in the past.

Futures contracts are not by themselves useful for all those who want to manage price risk. Futures contracts are available for only a few commodities and a few delivery locations. Nor are they available for deliveries a decade or more into the future. There is a robust business conducted outside exchanges, in the over-the-counter (OTC) market, in selling contracts to supplement futures contracts and better meet the needs of individual companies.

Options

An option is a contract that gives the buyer of the contract the right to buy (a call option) or sell (a put option) at a specified price (the "strike price") over a specified period of time. American options allow the buyer to exercise his right either to buy or sell at any time until the option expires. European options can be exercised only at maturity. Whether the option is sold on an exchange or on the OTC market, the buyer pays for it up front. For example, the option to buy a thousand cubic feet of natural gas at a price of $3.40 in December 2002 may cost $0.14. If the price in December exceeds $3.40, the buyer can exercise his option and buy the gas for $3.40. More commonly, the option writer pays the buyer the difference between the market price and the strike price. If the natural gas price is less than $3.40, the buyer lets the option expire and loses $0.14. Options are used successfully to put floors and ceilings on prices; however, they tend to be expensive.

Swaps

Swaps (also called contracts for differences) are the most recent innovation in finance. Swaps were created in part to give price certainty at a cost that is lower than the cost of options. A swap contract is an agreement between two parties to exchange a series of cash flows generated by underlying assets. No physical commodity is actually transferred between the buyer and seller. The contracts are entered into between the two counterparties, or principals, outside any centralized trading facility or exchange and are therefore characterized as OTC derivatives.

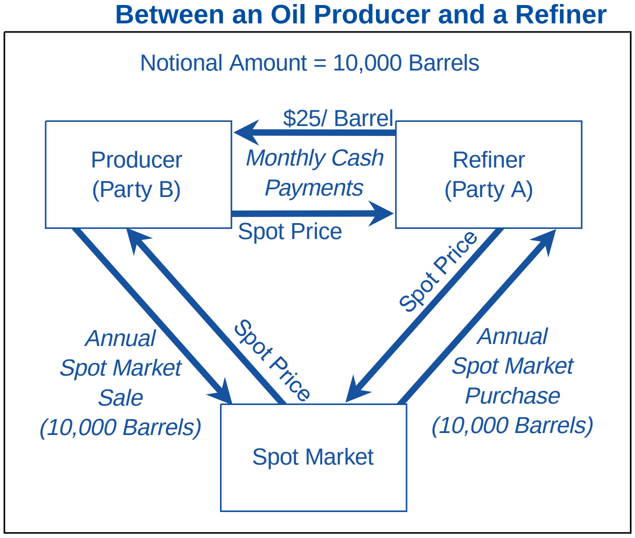
Because swaps do not involve the actual transfer of any assets or principal amounts, a base must be established in order to determine the amounts that will periodically be swapped. This principal base is known as the "notional amount" of the contract. For example, one person might want to "swap" the variable earnings on a million dollar stock portfolio for the fixed interest earned on a treasury bond of the same market value. The notional amount of this swap is $1 million. Swapping avoids the expense of selling the portfolio and buying the bond. It also permits the investor to retain any capital gains that his portfolio might realize.

Figure 1 illustrates an example of a standard crude oil swap. In the example, a refiner and an oil producer agree to enter into a 10-year crude oil swap with a monthly exchange of payments. The refiner (Party A) agrees to pay the producer (Party B) a fixed price of $25 per barrel, and the producer agrees to pay the refiner the settlement price of a futures contract for NYMEX light, sweet crude oil on the final day of trading for the contract. The notional amount of the contract is 10,000 barrels. Under this contract the payments are netted, so that the party owing the larger payment for the month makes a net payment to the party owing the lesser amount. If the NYMEX settlement price on the final day of trading is $23 per barrel, Party A will make a payment of $2 per barrel times 10,000, or $20,000, to Party B. If the NYMEX price is $28 per barrel, Party B will make a payment of $30,000 to Party A. The 10-year swap effectively creates a package of 120 cash-settled forward contracts, one maturing each month for 10 years.

So long as both parties in the example are able to buy and sell crude oil at the variable NYMEX settlement price, the swap guarantees a fixed price of $25 per barrel, because the producer and the refiner can combine their financial swap with physical sales and purchases in the spot market in quantities that match the nominal contract size. All that remains after the purchases and sales shown in the inner loop cancel each other out are the fixed payment of money to the producer and the refiner's purchase of crude oil. The producer never actually delivers crude oil to the refiner, nor does the refiner directly buy crude oil from the producer. All their physical purchases and sales are in the spot market, at the NYMEX price. Figure 2 shows the acquisition costs with and without a swap contract.

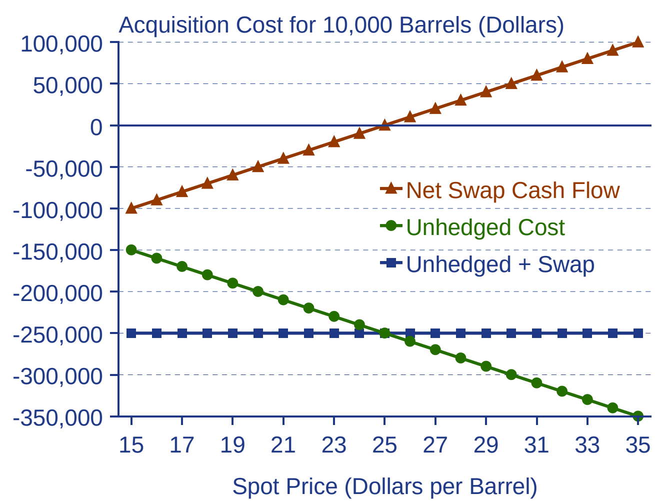
Many of the benefits associated with swap contracts are similar to those associated with futures or options contracts.[10] That is, they allow users to manage price exposure risk without having to take possession of the commodity. They differ from exchange-traded futures and options in that, because they are individually negotiated instruments, users can customize them to suit their risk management activities to a greater degree than is easily accomplished with more standardized futures contracts or exchange-traded options.[11] So, for instance, in the example above the floating price reference for crude oil might be switched from the NYMEX contract, which calls for delivery at Cushing, Oklahoma, to an

Figure 1. Illustration of a Crude Oil Swap Contract Between an Oil Producer and a Refiner



Source: Energy Information Administration.

Figure 2. Crude Oil Acquisition Cost With and Without a Swap Contract



Source: Energy Information Administration

[10]A portfolio of a put and a call option can replicate a forward or a swap. See M. Hampton, "Energy Options," in *Managing Energy Price Risk*, 2nd Edition (London, UK: Risk Books, 1999), p. 39.

[11]Swaps and other OTC derivatives differ from futures in another functional respect that is related in part to their lack of standardization. Because their pricing terms are not widely disseminated, swaps and most other OTC derivatives generally do not serve a price discovery function. To the extent, however, that swap market participants tend to settle on standardized contract terms and that prices for transactions on those swaps are reported, it is potentially the case that particular swaps could serve this function. An important example is the inter-bank market in foreign currencies, from which quotes on certain forward rates are readily accessible from sizable commercial banks.

Alaskan North Slope oil price for delivery at Long Beach, California. Such a swap contract might be more useful for a refiner located in the Los Angeles area.

Although swaps can be highly customized, the counterparties are exposed to higher credit risk because the contracts generally are not guaranteed by a clearinghouse as are exchange-traded derivatives.[12] In addition, customized swaps generally are less liquid instruments, usually requiring parties to renegotiate terms before prematurely terminating or offsetting a contract.

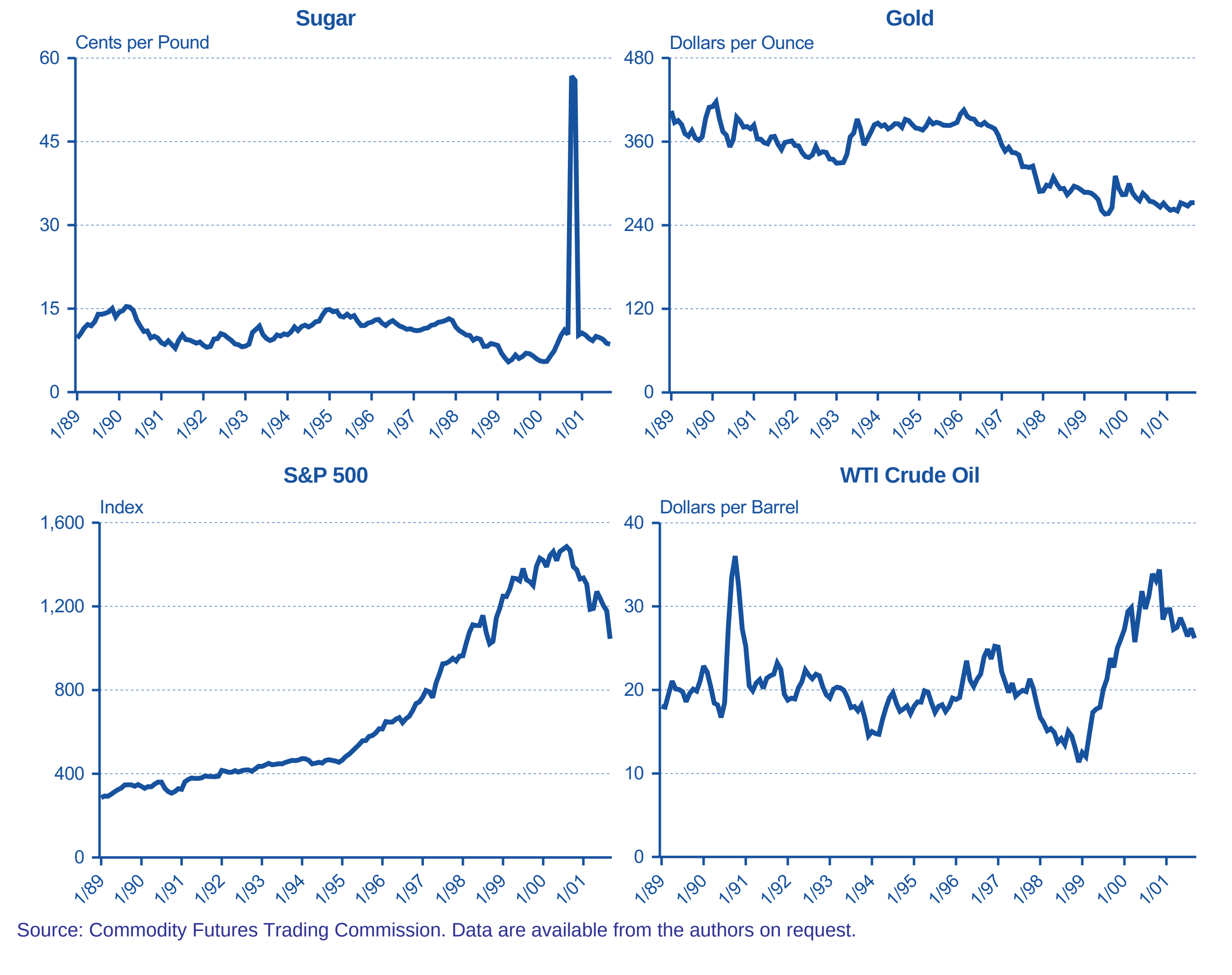
Energy Price Risk

Energy prices vary more than the prices of other commodities and are also sensitive to location. Price variation increases the difficulty of cash and credit management and of assessing the worth of prospective investments. Historical price data clearly illustrate the relatively high volatility of energy prices.

Figure 3 compares the spot prices for sugar, gold, and crude oil and an index of stock prices (S&P 500) from January 1989 to December 2001. The price of sugar can be seen to be fairly constant at around 10 cents per pound, except for a spike in late 2000 and early 2001. Gold prices, which ranged between roughly $350 and $420 per ounce from 1989 through 1995, have generally fallen since mid-1996. The S&P 500 index has generally risen in fits and starts to a peak in the early part of 2000, followed by a steep decline.

In contrast to the patterns apparent in other spot prices, energy commodity prices show no discernible trends. For example, Figure 4 shows spot market prices for crude oil (West Texas Intermediate at Cushing, Oklahoma), heating oil (New York Harbor), unleaded gasoline (New York Harbor), and natural gas (Henry Hub, Louisiana). The price of crude oil appears to fluctuate randomly around an average of about $20 per barrel, and heating oil and gasoline prices tend to move with

Figure 3. Spot Market Prices for Selected Commodities, January 1999-September 2001



Source: Commodity Futures Trading Commission. Data are available from the authors on request.

[12]EnergyClear (www.energyclear.com) is one, relatively new clearinghouse for OTC contracts. Like an exchange, this clearinghouse is the buyer and seller of all contracts, offers netting, and has margin requirements.

the oil price. The spot market price of natural gas peaks periodically with no obvious warning.

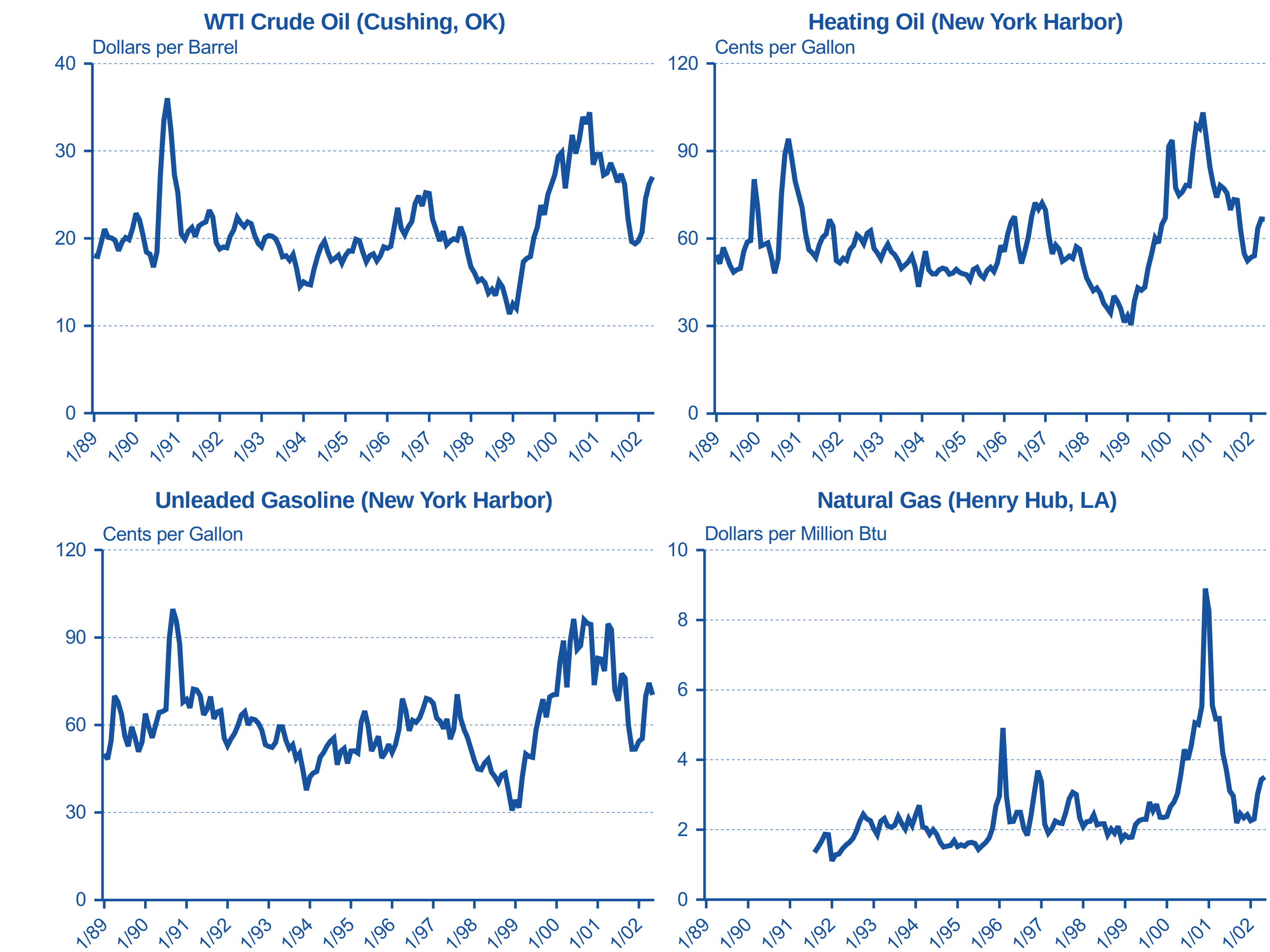
Wholesale electricity prices since 1999 (Figure 5) in the Midwest (ECAR) and Pennsylvania-Maryland-New Jersey (PJM) regions, at the California-Oregon border (COB), and at Palo Verde, a major hub for importing electricity into California, have shown a number of very large “spikes” during the summer months. In addition, wholesale electricity prices on the West Coast were extremely volatile in the winter and spring of 2001.

Natural gas and electricity are particularly subject to wide price swings as demand responds to changing weather. Inventories are of limited help in damping price spikes, because natural gas users typically do not maintain large inventories on site, and the options for storing electricity are few and expensive (pumped hydro, reservoirs, idle capacity, etc.). Shipping low-cost supplies to areas where prices are high can be very difficult in these industries because of limited capability on the physical networks connecting customers to suppliers. Limited storage capacity and the lack of cheaper alternative supplies from other areas can cause prices to soar in areas where demand increases suddenly.

Daily price volatility is the standard deviation of the percentage change in the commodity’s price. The standard deviation is a measure of how concentrated daily percentage price changes are around the average percentage price change. For a normal distribution, approximately 67 percent of all the percentage price changes will be within one standard derivation of the average percentage change. Volatility is usually expressed on an annual basis, where a year is understood to be the number of trading days, usually 252, in a calendar year. Annual volatility is calculated by multiplying daily volatility times 15.87, which is the square root of 252.

Price volatility is caused by shifts in the supply and demand for a commodity. Natural gas and wholesale electricity prices are particularly volatile for several reasons. Demand increases quickly in response to weather, and “surge” production is limited and expensive. In addition, neither can be moved to where it is needed quickly, and local storage is limited, especially in the

Figure 4. Spot Market Prices for Selected Energy Commodities, January 1999-May 2002



Source: Commodity Futures Trading Commission. Data are available from the authors on request.

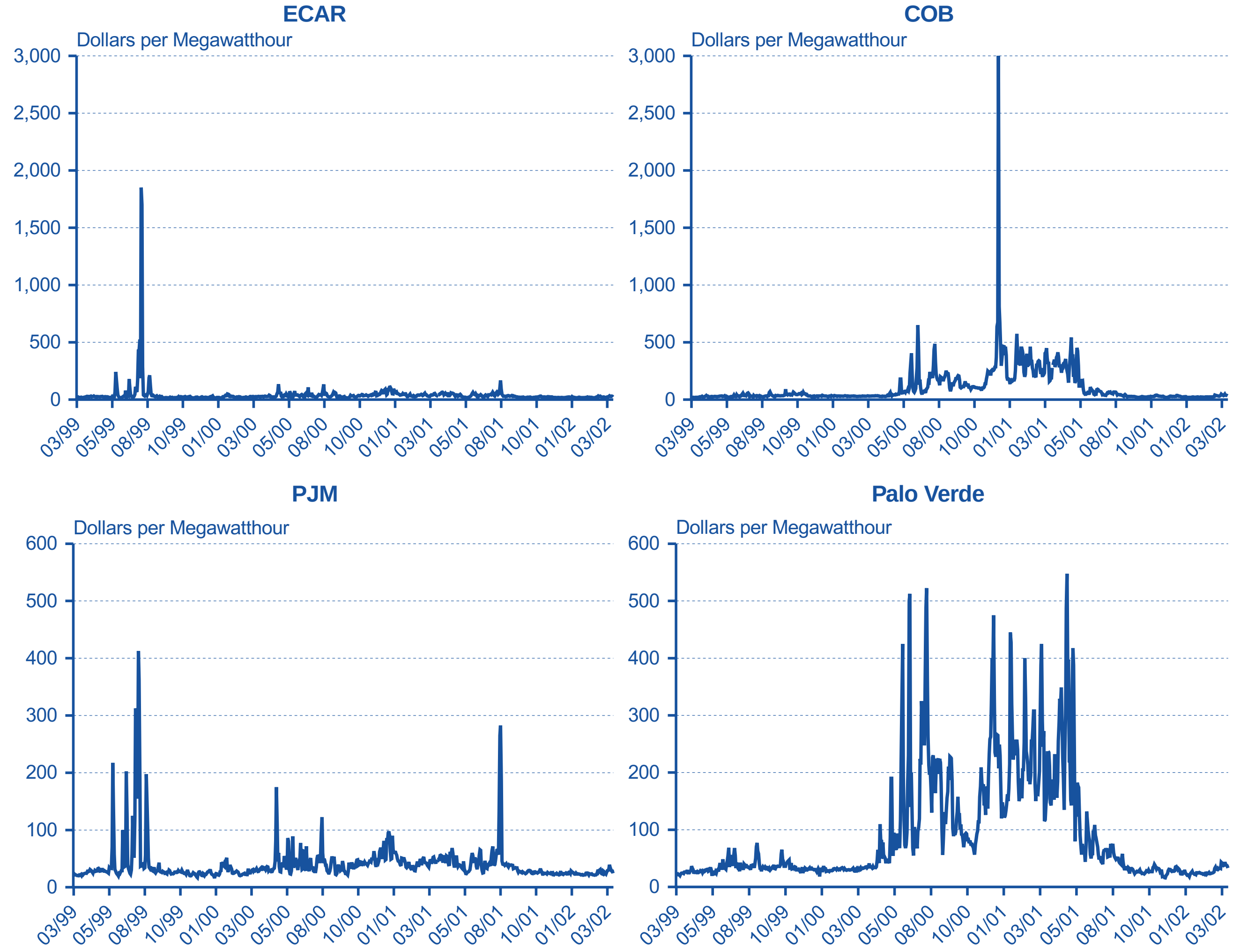
case of electricity. Public policy efforts to reduce volatility have focused on increasing reserve production capability and increasing transmission and transportation capability. Recently there has been an emphasis on making prices more visible to users so that they will conserve when supplies are tight, thus limiting price spikes.

The average of the annual historical price volatility for a number of commodities from 1992 to 2001 is shown in Table 3. The financial group has the lowest overall volatility, and the electricity group has by far the highest. Generally, energy commodities have distinctly higher volatility than other types of commodities. The following example illustrates the impact of price volatility on the profitability of investments in electricity generation capacity.

Price Risk and Returns to Investment in a New Combined-Cycle Generator

EIA forecasts indicate that meeting U.S. demand for electricity over the next decade will require about 198 gigawatts of new generating capacity. About 7 gigawatts of the required new capacity is projected to come from coal-fired plants, 170 gigawatts from natural-gas-fired combined-cycle and combustion turbine plants, and the remainder from other technologies.[13] Investment in the new projects will depend on how investors assess future natural gas and electricity prices and the consequences of price variation for cash earnings and project returns.

Figure 5. Wholesale Electricity Prices in Selected Regions, March 1999-March 2002



Source: Commodity Futures Trading Commission. Data are available from the authors on request.

[13]The other technologies include nuclear capacity expansions, fuel cells, renewable technologies, and cogenerators. Together they are expected to account for the remaining 21 gigawatts of additional new capacity. Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Table A9.

The case of a typical gas-fired combined-cycle plant shows what is at stake. Investors compare the cost of a new plant with the cash it is expected to generate over the life of its operation. The conventional way of making the comparison is called net present value (NPV) analysis. The stream of cash payments to investors is called the net cash flow. Each year's net cash return is adjusted for the time value of money (the implicit interest on delayed receipt) and for risk—i.e., discounted at the firm's cost of capital. The discounted net cash flows are added up, and the resulting sum is called the present value of net cash flows. If the present value of future net cash flows exceeds the initial investment, then the project is economical and should be undertaken.[14] Such projects are said to have a positive net present value and projects with a negative net present value should not be undertaken.[15]

Table 4 shows the cash flows that a new generator would be expected to produce under a recent EIA forecast of natural gas and electricity prices.[16] Details of this and other calculations in this example are included in Appendix B. Over its 20-year life, the project has a positive NPV of $2,118,017.[17] Thus, the power plant should

Table 3. Spot Market Price Volatility for Selected Commodities

Commodity	Average Annual Volatility (Percent)	Market	Period
Electricity			
California-Oregon Border	309.9	Spot-Peak	1996-2001
Cinergy	435.7	Spot-Peak	1996-2001
Palo Verde	304.5	Spot-Peak	1996-2001
PJM	389.1	Spot-Peak	1996-2001
Natural Gas and Petroleum			
Light Sweet Crude Oil, LLS	38.3	Spot	1989-2001
Motor Gasoline, NYH	39.1	Spot	1989-2001
Heating Oil, NYH	38.5	Spot	1989-2001
Natural Gas	78.0	Spot	1992-2001
Financial			
Federal Funds Rate	85.7	Spot	1989-2001
Stock Index, S&P 500	15.1	Spot	1989-2001
Treasury Bonds, 30 Year	12.6	Spot	1989-2001
Metals			
Copper, LME Grade A	32.3	Spot	January 1989-August 2001
Gold Bar, Handy & Harman, NY	12.0	Spot	1989-2001
Silver Bar, Handy & Harman, NY	20.2	Spot	January 1989-August 2001
Platinum, Producers	22.6	Spot	January 1989-August 2001
Agriculture			
Coffee, BH OM Arabic	37.3	Spot	January 1989-August 2001
Sugar, World Spot	99.0	Spot	January 1989-August 2001
Corn, N. Illinois River	37.7	Spot	1994-2001
Soybeans, N. Illinois River	23.8	Spot	1994-2001
Cotton, East TX & OK	76.2	Spot	January 1989-August 2001
FCOJ, Florida Citrus Mutual	20.3	Spot	September 1998-December 2001
Meat			
Cattle, Amarillo	13.3	Spot	January 1989-August 2001
Pork Bellies	71.8	Spot	January 1989-August 1999

Sources: Energy Information Administration and Commodity Futures Trading Commission. Data are available from the authors on request.

[14]This assumes a "now or never" choice—that is, an irreversible investment decision. In reality, investors can sometimes postpone investing until they have more information. This is called the real options approach (the option to defer is one form of real option). Perhaps more important is the option to turn the plant on and off on individual dates and hours—i.e., to convert gas to power only when the relative prices are right. The static NPV approach assumes that the plant will run even when gas prices are too high to allow for a profit on the electricity that is generated.

[15]A somewhat different approach is to compute the internal rate of return—i.e., a discount rate that would set the NPV of the project to zero. This return is compared with the cost of capital, and if the internal rate of return is greater than the cost of capital, the project should be undertaken. A similar analysis was carried out using this approach.

[16]Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Tables A3 and A8.

[17]The calculation assumes that the firm's cost of capital (discount rate) is constant over time and is not affected by the amount of funds invested in the project. This assumption avoids the problems imposed by capital rationing and varying money and capital market rates.

be built because it would be profitable, generating an additional $2 million for the investment after satisfying obligations to debt holders (interest payment at 10.5 percent) and equity holders (equity cost of dividends and / or capital gains of 17.5 percent). Moreover, after the initial investment it generates positive net cash flows in every year.

When input and output prices are uncertain, the NPV is no longer a single number but a distribution. Under wholesale price deregulation, investors in generators face not only fuel price risk but also electricity price risk. As shown in Figure 5 above, electricity prices have been very volatile in California and PJM for the past few years. From a generator's point of view, increased electricity price is not a concern; however, lower price can affect the viability of the new investment. Simulating future outcomes by assuming historical volatilities is one way to calculate the probability distribution of a project's NPV.[18] Among other things, the distribution of NPV shows the probability that an investment will turn out to be profitable after the fact.

Figure 6 shows the impact on the NPV of the investment when electricity and natural gas prices are varied by plus and minus 77 percent and 47 percent, as a standard deviation, from their expected prices, respectively.[19] In this simulation, there is an 83-percent probability that the project's NPV would be at least zero, with mean of $110 million, and a 17-percent probability that it would be unprofitable.[20] A summary of the simulation results is shown in Table 5. Despite the significant probability of failure, it makes economic sense for society to invest in the generator, because the project has a single positive

Table 4. Expected Annual Net Cash Flows and Net Present Value (NPV) of Investment in a New Generator

	After-Tax Net Cash Flows		Electricity Price (Cents per Kilowatthour)		Fuel Cost (Dollars per Million Btu)	
Year	Outflow	Inflow	Mean	Standard Deviation	Mean	Standard Deviation
2001	$236,000,000	—	—	—	—	—
2002	—	$36,397,248	4.215	3.246	2.590	1.218
2003	—	$34,065,271	3.983	3.067	2.921	1.373
2004	—	$31,645,037	3.974	3.060	3.123	1.468
2005	—	$29,628,339	3.902	3.004	3.194	1.501
2006	—	$27,823,397	3.816	2.938	3.225	1.516
2007	—	$26,633,754	3.769	2.902	3.258	1.531
2008	—	$25,720,350	3.737	2.878	3.313	1.557
2009	—	$33,451,675	3.719	2.864	3.343	1.571
2010	—	$26,061,919	3.741	2.881	3.381	1.589
2011	—	$25,939,059	3.758	2.894	3.460	1.626
2012	—	$25,134,117	3.732	2.874	3.524	1.656
2013	—	$38,647,637	3.746	2.884	3.572	1.679
2014	—	$25,094,989	3.735	2.876	3.610	1.697
2015	—	$41,493,066	3.740	2.880	3.654	1.718
2016	—	$25,627,301	3.760	2.895	3.685	1.732
2017	—	$23,837,762	3.797	2.924	3.729	1.752
2018	—	$22,297,428	3.847	2.962	3.777	1.775
2019	—	$22,945,190	3.877	2.985	3.818	1.795
2020	—	$23,656,442	3.916	3.015	3.871	1.819
2021	—	$24,295,166	3.916	3.015	3.871	1.819
NPV at 11.03 percent weighted average cost of capital = $2,118,017				Rate of return on investment = 11.18 percent		

Sources: **Expected Mean Prices:** Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), Tables A3 and A8. **Standard Deviations:** Calculation based on historical data from Platts.

[18]The use of simulation analysis in capital budgeting was first reported by David Hertz. See D.B. Hertz, "Risk Analysis in Capital Investment," *Harvard Business Review* (January-February 1964), pp. 95-106; and "Investment Policies That Pay Off," *Harvard Business Review* (January-February 1968), pp. 96-108. The simulation is a tool for considering all possible combinations and, therefore, enables analysts to inspect the entire distribution of project outcomes.

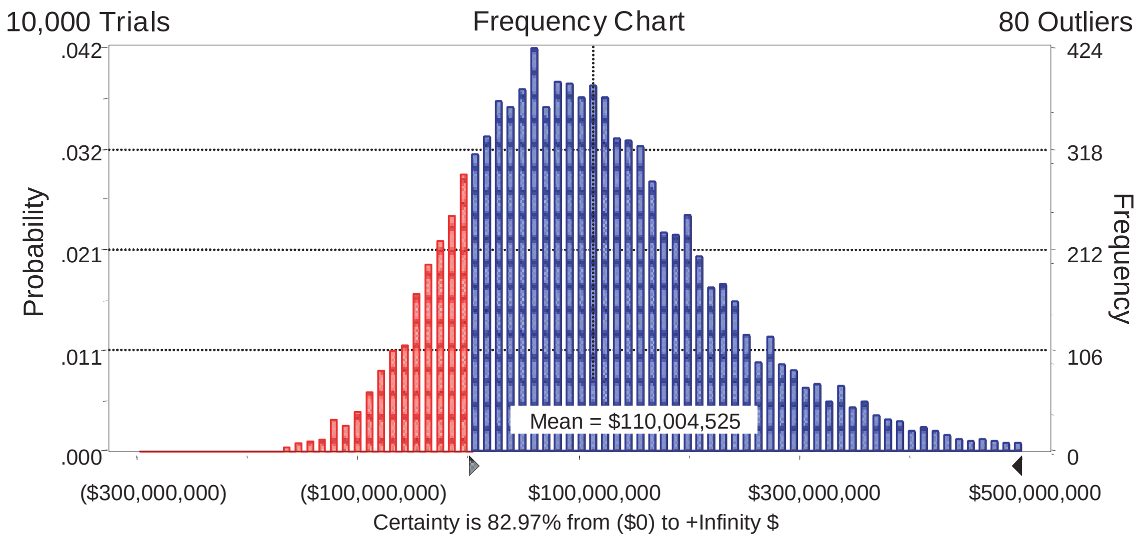
[19]Based on published NYMEX historical spot data in ECAR, PJM, COB, and Palo Verde from March 1999 to March 2002, the average mean and standard deviation of electricity prices are 6.66 and 5.11 cents per kilowatthour. For the same time periods, the average and standard deviation of the Henry Hub Gulf Coast natural gas spot price are 3.522 and 1.648 dollars per million Btu. As a result, the standard deviations used here for the price of electricity and natural gas are 77 percent (5.11 / 6.66) and 47 percent (1.648 / 3.522) of the expected mean prices for the corresponding years for the project's life.

[20]This simulation was performed using a risk-free rate as a discount rate rather than the weighted average cost of capital. See Appendix B for detailed calculations.

NPV of $2,118,017.[21] The problem is that individual investors, not society as a whole, bear the risk if the investment goes wrong.

To the extent that prices vary because of rapid changes in supply and demand, energy price volatility is evidence that markets are working to allocate scarce supplies to their best uses. As shown by the example, however, price variation also has the effect of making energy investment risky. Investors have difficulty judging whether current prices indicate long-term values or transient events. Bad timing can spell ruin. In addition, even good investments can generate large temporary cash losses that must be funded.

Figure 6. Net Present Value (NPV) Simulation Results



Source: Energy Information Administration.

Table 5. Summary of Simulation Results

Statistic	Net Present Value (NPV)
Mean	$110,004,525
Median	$95,713,767
Standard Deviation	$120,382,899
Maximum	$1,187,415,173
Minimum	-$213,218,338
Probability of NPV > 0	82.97%
Coefficient of Variation	1.09

Sources: **Expected Mean Prices:** Calculated from Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383 (2002) (Washington, DC, December 2001), Tables A3 and A8. **Standard Deviations:** Calculation based on historical data from Platts.

[21] Economically speaking, an investment decision should be based on NPV criteria, because the NPV methodology implies risk and opportunity cost of an investment. On the other hand, a whole distribution of NPVs obtained by simulation will help guide an investor to know the danger and the actions that might be taken to guard the investment.